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DIRECT TESTIMONY OF PROGRESS ENERGY CAROLINAS, INC.**

WITNESS RONNIE M. COATS

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1 **Q. Mr. Coats will you please state your full name.**

2 A. My name is Ronnie M. Coats

3 **Q. On whose behalf are you presenting testimony?**

4 A. I am presenting my testimony on behalf of Progress Energy Carolinas, Inc.

5 **Q. Please summarize briefly your educational background and experience.**

6 A. I graduated from North Carolina State University in 1967 with a B.S. Degree in
7 Chemical Engineering. I also obtained a Master of Business Administration
8 Degree from the University of North Carolina at Chapel Hill in 1989. I am a
9 member of Professional Engineers of North Carolina (PENC) and the Air and
10 Waste Management Association. I am also a registered Professional Engineer in the
11 state of North Carolina. I joined CP&L in 1968 and have held several engineering
12 and management positions related to the design, construction, and operation of
13 generating plants. These include: Principal Engineer, Manager of Generation
14 Services, and Manager-Environmental Compliance. In December, 2001, I assumed
15 the position of Senior Fuels Coordinator in the System Resource Planning Section
16 of Carolina Power and Light Company's System Planning and Operations
17 Department. In that position, I was responsible for maintaining oversight of fuel
18 planning and procurement activities related to CP&L's regulated fleet to ensure
19 that a reliable and economical supply of fuel was available to meet the operating
20 requirements of the regulated generating facilities. I formally retired in July, 2004.

1 Since that time I have been employed by ESG International on assignment to
2 Progress Energy Carolinas and performing the duties of Senior Fuels Coordinator.

3 **Q. What is the purpose of your testimony here today?**

4 A. The purpose of my testimony is to present fuel cost data for the historical test
5 period of January 2004 through March 2005, projected fuel cost data for the period
6 July 2005 through June 2006, and to show the reasonableness of the Company's
7 fuel purchasing practices.

8 **Q. How much contract coal and spot coal did the Company receive during the**
9 **January 2004 through March 2005 test period?**

10 A. The Company received 9,551,802 tons of term coal at an average cost of
11 \$2.21/MmBtu and 5,006,453 tons of spot coal at an average cost of \$2.35/MmBtu .
12 On a \$/ton basis, the term coal was delivered at a cost of \$55.01/ton and the spot
13 coal was delivered at a cost of \$57.96/ton. These statistics are net of Power
14 Agency (PA) ownership.

15 **Q. What was the Company's inventory of coal at the end of March, 2005?**

16 A. The coal net inventory as of March 31, 2005 was 1,212,797 tons (net of PA).

17 **Q. Please describe Coats Exhibit No. 1.**

18 A. Coats Exhibit No. 1 shows the quality of coal received each month during the
19 period.

20 **Q. What was the average nuclear fuel cost for the generation of electricity during**
21 **the period January 2004 through March 2005?**

22 A. The average cost of nuclear fuel consumed in the generation of electricity during
23 that period was \$0.41 /MmBtu (net of PA)

1 **Q.** **During the period January 2004 through March 2005, how many gallons of**
2 **No. 2 fuel oil did the Company receive and at what cost?**

3 A. The Company received a total of 15,165,719 gallons of No. 2 fuel oil at an average
4 cost of \$1.29/gallon (\$9.374/MmBtu) for that period. These statistics are also net
5 of PA ownership.

6 **Q.** **What was the Company's closing oil inventory on March 31, 2005?**

7 A. The Company's closing oil inventory on March 31, 2005 was 37,829,665 gallons
8 (net of PA) of No. 2 fuel oil.

9 **Q.** **How much natural gas did the Company burn during the period January 2004**
10 **through March 2005?**

11 A. The Company burned 20,774,548 decatherms (Dt) of natural gas for the period at a
12 delivered cost of \$8.37/Dt

13 **Q.** **Were the inventory levels maintained during the test period appropriate and**
14 **were your fuel procurement practices reasonable and prudent?**

15 A. Yes. As I will detail later in my testimony, the inventory levels ensured an
16 adequate supply of fuel to meet our customers' electrical requirements during this
17 period and the fuel was secured at a reasonable cost utilizing prudent procurement
18 practices and procedures. Progress Energy Carolinas continuously evaluates the
19 term and spot markets for coal, nuclear, oil and natural gas in order to determine
20 the appropriate portfolio of long term and spot purchases of fuels that ensure a
21 reliable supply of electricity to our customers at the lowest reasonable prices. Such
22 evaluations include daily, weekly and monthly solicitations, subscription to fuel
23 pricing services and trade publications and outside consultants.

1 **Q. What types of coal does PEC burn in its plants?**

2 A. PEC's coal fueled plants are all designed to burn high BTU bituminous coal. Our
3 environmental permits also require that we burn a coal that is relatively low in
4 sulfur. With the exception of Roxboro Unit 4 and Mayo Unit 1, all of our coal fired
5 plants in North Carolina must burn coal having a sulfur dioxide (SO₂) content no
6 greater than 2.3 lbs SO₂/mmBtu. To meet environmental requirements, Roxboro
7 Unit 4 and Mayo Unit 1 must burn coal having a SO₂ content no greater than 1.2
8 lbs. SO₂/mmBtu, which is known as compliance coal. Our coal fired Robinson
9 Unit 1, located in South Carolina, can burn coal with a sulfur content no greater
10 than 3.5 lbs/mmBtu. While the sulfur limit for Robinson 1 is higher than our North
11 Carolina plants, the coal utilized there, like the coal at our other plants, is still a
12 typical Central Appalachian (CAPP) coal. Historically, compliance coal has
13 comprised about 28-30% of our annual coal requirements, or about 3.6 million
14 tons. As I will discuss later, the SO₂ content of a coal has a direct impact on the
15 cost of the coal.

16 **Q. Do other utilities regulated by this Commission burn compliance coal?**

17 A. No. The requirement for compliance coal at Roxboro Unit 4 and Mayo Unit 1 is
18 unique to PEC. This requirement results from the United States Environmental
19 Protection Agency's New Source Performance Standard, Subpart D, which allows
20 large boilers which commenced construction between August 17, 1971 and
21 September 18, 1978, to use compliance coal to meet SO₂ emissions requirements
22 rather than install SO₂ emission reduction equipment, such as scrubbers. Units that
23 commenced construction after September 18, 1978 had to meet more stringent

1 requirements which included the use of Scrubbers. Neither Duke nor SCE&G have
2 units covered by the Subpart D (i.e. compliance coal) requirements.

3 In order to meet the requirements of the North Carolina Smokestacks Act, PEC is
4 now in the process of installing scrubbers at its Roxboro and Mayo plants.
5 Completion of these scrubber installations will allow PEC to burn higher sulfur,
6 and currently less expensive, coal in these plants. PEC anticipates completing the
7 installation of this equipment by 2009.

8 **Q. Does the sulfur limitation that you have to meet influence the cost of the coal**
9 **you buy?**

10 A. Yes, from at least two perspectives. First, under current environmental regulations,
11 the operator of a coal fired unit must hold a SO2 emission allowance for every ton
12 of SO2 emitted during the operation of that unit. SO2 emission allowances have a
13 market value and thus influence the cost of coal. The lower sulfur coals will emit
14 less SO2 and will therefore require less emission allowances. Thus increases in the
15 cost of SO2 allowances will tend to increase the premium one has to pay for lower
16 sulfur coal. In the case of our plants, we see a significant difference between the
17 market prices for compliance coal at Roxboro Unit 4 and Mayo Unit 1 and our
18 other plants. The premium for compliance coal over non-compliance has increased
19 from about \$1.95/ton in 2002 to \$3.47/ton in 2004. Currently the premium is over
20 \$4.50/ton.

21 Secondly, the SO2 limits that we have to meet precludes, at the present time, the
22 use of most Northern Appalachian (NAPP) coals or coals from the Illinois Basin.
23 Coals from these regions typically have sulfur contents greater than we are allowed

1 to burn and they would require increased transportation costs. Coats Exhibit No.2
2 is a map showing the location of these coal regions. Therefore, our domestic
3 sources of coal are limited to the low to mid-range sulfur coals in the CAPP region.
4 While there is some degree of competition available in this region, we have seen a
5 weakening in competition in the last few years. The availability of compliance coal
6 production in CAPP on the Norfolk Southern Railroad ("NS") has been limited to
7 five (5) producers and two of those reserves (Arch's Mingo Logan and Alliance's
8 Pontiki) are depleting and will not be available in the future. This is important as
9 our compliance coal units are served exclusively by the NS railroad.

10 **Q. What are the sources of coal PEC burns in its coal plants?**

11 A. As previously stated, our coal plants are designed to burn coal with the quality
12 characteristics (heat content, sulfur content, ash content, etc.) typical of coals from
13 the Central Appalachian coal region. We are also able to burn coal from foreign
14 sources provided the coals meet the quality requirements of our plants.

15 **Q. How is coal transported to PEC from these sources?**

16 A. For the most part, coal is transported from mines in CAPP to individual plants by
17 rail using either the CSX railway or the Norfolk & Southern (NS) railway. We
18 receive a limited amount of coal by truck at our Asheville Plant and since January
19 2003 have been able to receive foreign coal by barge at our Sutton Plant. Our
20 Roxboro and Mayo plants (which are our largest coal plants, with total generating
21 capacities of 3207 MW) and Asheville plant are served solely by the NS railway.
22 The Robinson, Weatherspoon, and Sutton Plants are served solely by the CSX
23 railway. The Lee and Cape Fear Plants are served by both CSX and NS. PEC's

1 total coal fired generation capacity is 5285 MW, so you can see that the Roxboro
2 and Mayo baseload plants, which are served exclusively by NS, consume most of
3 our coal (over 70%). This is an important fact when looking at our delivered cost of
4 coal that I will explain later in my testimony.

5 **Q. Mr. Coats, please describe the Company's coal procurement practices.**

6 A. The Company continues to follow the same procurement practices that it has
7 historically followed, and a summary of those practices is as follows:

- 8 1. **Estimating Fuel Requirements:** Fuel requirements are estimated annually
9 using a long-term forecasting simulation model and monthly using a short-
10 term simulation model. Both simulation models factor in load forecast,
11 system planning and capacity factors for all generating plants.
- 12 2. **Establish Inventory Requirements.** On an annual basis, the department
13 uses a systematic inventory modeling process developed by North Carolina
14 State University to evaluate probabilities and quantify potential risks that
15 could potentially impact inventory levels. The outcome of the model is
16 optimal inventory levels for each plant given potential risks such as losing a
17 coal handling system or a strike by the railroad.
- 18 3. **Monitoring On-going Fuel Requirements.** On a monthly basis, there is a
19 review and evaluation of current inventory levels, supplier performance
20 with respect to shipments, forecasted short-term requirements and
21 commitments to determine additional fuel requirements spot and/or
22 contract.

- 1 4. **Develop Qualified Supplier List.** A list of qualified suppliers is
2 maintained throughout the year and to the extent possible capabilities of
3 suppliers are evaluated including current performance, reserves, coal
4 quality, railroad origination condition of supplier and loading capabilities.
- 5 5. **Bid Requests.** At least once a year, a formal solicitation is sent out to all of
6 our qualified suppliers for spot and/or longer term coal.
- 7 6. **Bid Evaluation.** Contracts are awarded after a thorough evaluation process
8 including an economic evaluation, financial and credit review of the
9 supplier, performance evaluation, coal quality conformance with plant
10 requirements, supplier quality controls are in place, test burns (if necessary)
11 and compliance with federal EPA environmental regulations.
- 12 7. **Spot Purchases.** To supplement our fuel supply, short-term spot offers are
13 solicited as needed and purchases made in accordance to needs. Please note
14 these purchases may be for as few as one train. In today's environment
15 with coal availability being extremely tight, suppliers have 3-4 customers
16 who all want the same coal, and the response to vendor proposals must be
17 timely.
- 18 8. **Expediting of Purchases.** All purchases are expedited, administered and
19 monitored to ensure compliance with all contractual terms of the agreement.
- 20 9. **On-going Quality Control.** The Company requires suppliers to sample,
21 analyze and weigh all coal shipped under the agreements using independent
22 third party labs (ASTM Standards) and weigh with certified scales. Three
23 to four samples are typical with one sample being a referee sample should a

1 dispute arise. Sample analyses are used for contractual quality pricing
2 adjustments. Weighing is done at the mine using certified scales and if no
3 scales are certified at the mine, certified railroad scales are used in route to
4 plant.

5 **Q. How do you make the determination of how much coal to place under contract**
6 **and how much to depend on the spot market?**

7 A. Historically, the decision of how much of our projected coal demand to have under
8 contract was based on judgment applied during the procurement process
9 considering factors such as price trends, expected market volatility, known or
10 anticipated issues that could impact supply, etc. For example, if market forecasts
11 indicated stable or declining prices, the amount under contract at any point in time
12 would likely be less than if prices or market volatility were increasing. This
13 decision is always a balancing act to ensure a reliable supply in the quantities and
14 quality needed without being over or under committed at any given time. These
15 decisions are implemented by negotiating contracts with terms of 1 year or less
16 (spot purchases) and contracts having terms greater than one year (term purchases).
17 In recent years, we have generally not entered into contracts exceeding 3 years
18 because of the higher level of uncertainty associated with price forecasts for longer
19 periods of time and the fact that suppliers were not willing to commit to reasonable
20 firm pricing for longer periods of time.

21 **Q. How much of the coal needed by PEC during the period April 2004 through**
22 **March 2005 was forecasted to be under contracts and how much was**
23 **forecasted to be purchased later?**

1 A. At the time of the forecast used in the PEC's 2004 fuel case to establish a fuel
2 factor for the year ending March 31, 2005, we forecast a requirement for
3 11,408,556 tons of coal. At that time, we had 8,658,000 tons of coal under contract
4 (spot and term) for delivery during that period. Actual coal requirements during
5 the period were 12,079,648 tons. Therefore, the amount under contract at the time
6 of the forecast represented 76% of our projected need at that time and 72% of our
7 actual requirements during that period. Coal not under contract at the time of the
8 forecast would be purchased later, under a combination of spot and term contracts,
9 to meet the actual requirements during the period.

10 **Q. Was all of the coal that you contracted for delivery during the April 2004**
11 **through March 2005 period delivered on the schedule contemplated by the**
12 **contracts?**

13 A. No. About 1.3 million tons of coal scheduled for delivery during this period was
14 not delivered on schedule.

15 **Q. How did you make up for the shortfall in delivery of contracted coal and for**
16 **the additional requirements that you actually needed?**

17 A. Additional coal was purchased and delivered to make up for the shortfall in
18 delivery and to cover the additional requirements that we experienced during this
19 period.

20 **Q. Why was coal under contract not delivered as scheduled?**

21 A. During 2004, there were several factors that disrupted both the ability of the
22 railroads to deliver coal and the ability of the mines in the CAPP region to supply
23 coal. Flooding in West Virginia and Kentucky, especially during the late spring

1 and late summer period, impacted both mining operations and rail operations. The
2 flooding resulted in limiting production capability and washed out rail tracks at
3 mine loadout facilities prevented trains from being loaded on schedule. The heavy
4 rains also led to production stoppages due to roof falls and other adverse mining
5 conditions. Additionally, several suppliers were experiencing financial difficulties
6 which impacted their ability to meet production schedules. For example, our
7 largest single supplier was in bankruptcy in 2004 and deliveries were erratic and
8 unreliable. In addition, enforcement of stricter truck weight limits in West
9 Virginia increased mining costs and production because the mines were required to
10 haul fewer tons per truck. Increased mining and mine reclamation permit
11 restrictions limited the ability of mines to expand or open new production areas.
12 Finally, increased demand for export coal and other high revenue commodities led
13 the railroads to allocate more resources to higher revenue producing operations.
14 This led to a shortage of locomotive power, crews, and railcars to serve the
15 domestic coal markets. All of these factors, acting together, disrupted deliveries for
16 PEC as well as other users of CAPP coal.

17 **Q. What remedies are available to PEC when contract coal is not delivered on**
18 **schedule?**

19 A. It is an industry practice to allow "make up" shipment of tons from suppliers who
20 are willing to satisfy their contractual obligations if they fall behind. Other
21 remedies might include terminating the contract or litigation, but neither of these
22 remedies are productive because what we need and want is the coal. In addition
23 there would be significant time and cost associated with any potential legal remedy

1 related to supplier contract defaults with no guarantee of success. Since we are
2 currently in a seller's market, it is very difficult to include substantial liquidated
3 damage language into coal contracts. The sellers will simply take their coal
4 elsewhere.

5 **Q. What action has PEC taken to resolve this matter with the companies who**
6 **failed to deliver as contracted?**

7 A. PEC evaluated each contract and determined appropriate corrective action. The
8 cause of missed shipments included supplier failure to load, force majeure and poor
9 railroad performance. In most cases where the contracted volume was not shipped,
10 the primary cause was difficulties with railroad scheduling (i.e., rationing of
11 permits) and reliability of railroad performance due to shortage of locomotive
12 power, equipment and crews. Suppliers were contacted to ascertain whether or not
13 missed tonnage could be made up. Plans were finalized to recover approximately
14 half of the missed tonnage in a future period. In other cases, due to reduced
15 reliability of railroad performance, the volume was not contractually required to be
16 made up. Some of these cases remain in dispute and we are uncertain at this time
17 whether or not we will receive all tons not shipped during the test period.

18 **Q. In PEC's 2004 fuel case, what coal requirements (quantity and price) did PEC**
19 **forecast for the period April, 2004 through March, 2005, exclusive of**
20 **transportation costs?**

21 A. As shown on Coats Exhibit No. 3, PEC projected a need for 11,408,556 tons of
22 coal at an average price of \$31.66/ton, exclusive of transportation. The exhibit
23 provides a further breakdown of these projections by compliance and non-

1 compliance coal.

2 **Q. What were PEC's actual coal quantity and costs for the period April, 2004**
3 **through March, 2005?**

4 A. Again referring to Coats Exhibit No. 3, the actual system coal requirement during
5 this period was for 12,079,648 tons at an average cost of \$42.01/ton, exclusive of
6 transportation.

7 **Q. Please explain why coal prices have risen during the last 12 to 18 months.**

8 A. Coats Exhibit No. 4 graphically illustrates how the market price of CAAP coal has
9 increased during the last 18 months. As shown, market prices increased from the
10 low \$40/ton range at the beginning of 2004 (shortly after the forecast used in PEC's
11 2004 fuel case) to over \$50/ton in April 2004, and to a peak of \$65-70/ton in mid
12 2004. Prices have fluctuated somewhat since then and as of April 2005 were in the
13 range of \$60.00-68.50/ton. There are a number of factors causing this increase.

14 First, production costs have increased. Labor, fuel, mining materials such as steel
15 and explosives and environmental costs have all increased, and overall mining
16 costs are up 20%-35% in the last 12-18 months. Secondly, the demand for coal in
17 Asia, in particular China, has greatly increased. At the same time demand has
18 increased, CAPP supply is decreasing. Permitting difficulties have made it
19 extremely difficult to boost production at existing mines and/or open new mines.
20 Lower cost coal reserves are being depleted so more expensive coal is being mined
21 to meet market demand. Several large eastern coal producers experienced financial
22 troubles and sought bankruptcy protection thus reducing and/or terminating
23 production at their high cost mines as a means to lower production costs. In

1 addition, the inability of these same producers to raise new capital to expand their
2 operations resulted in higher cost coal. Finally, on a price per BTU basis, natural
3 gas is twice as expensive as coal. Thus, coal venders face no real commodity
4 competition to put any downward pressure on coal prices.

5 Despite this sudden and significant run up in coal prices, the Company's overall
6 coal costs April 2004 through March 2005 period were significantly below
7 prevailing market prices. This is illustrated in Coats Exhibit No.5 which compares
8 the historic spot market price curve with PEC actual spot prices. As this chart
9 shows, even with constantly rising prices during the period of April 2004 through
10 March 2005, we were successful in purchasing coal at less than market prices.

11 **Q. Why did the quantity of coal actually used during the period April 2004**
12 **through March 2005 exceed your forecast?**

13 A. Actual coal burned is a function of the overall operation of our integrated power
14 system to meet total load demand. Since units are dispatched based on current
15 price signals, it is not unusual for the actual fuel requirements for any given fuel to
16 differ from forecasts that are based on a fixed price signal and are generally done
17 months before the actual operating period in question. Factors such as changing
18 fuel prices, system load and energy demand, generating unit outage plans and
19 operating performance, environmental factors, etc. will combine to create
20 differences between the forecast requirements and actual requirements. For the
21 period of April 2004 through March 2005, several factors led to differences
22 between the forecast and actual requirements. First, the actual system generation
23 for load during this period was 1.7 million Mwh greater than forecast. Obviously

1 meeting increased load requires more fuel. Since our nuclear units operate at full
2 load, any increase in demand always comes from other system resources such as
3 coal-fueled plants. Secondly, for the period, the contribution from our nuclear
4 plants was about 500,000 Mwh less than planned. This decrease in nuclear
5 production for the period was made up from other system resources. In 2004,
6 another factor that could impact our generation mix was introduced. For the first
7 time, we had to meet Nitrogen Oxides (NOx) emissions requirements during the
8 ozone season (June through September in 2004). These requirements meant that
9 during the 2004 ozone season, we had to have a NOx emission allowance for each
10 ton of NOx emitted. Like SO2 emission allowances, NOx allowances have a
11 market value and are treated as a variable cost for unit dispatch purposes. The
12 impact of the NOx allowance cost on the dispatch order depends on the NOx
13 emission rate for any given unit, the market price for the NOx emission allowances
14 and the relative price difference between the price coal and gas. The NOx emission
15 rates for our smaller coal-fueled units exceed the rates from our larger coal units
16 (which are equipped with sophisticated NOx controls) by a factor of 4-8 times,
17 depending on the specific unit. The smaller coal-fueled unit's NOx rates exceed
18 the emission rate from our gas-fueled Richmond County Combined Cycle unit by
19 up to 80 times. This difference in emission rates, combined with the price of NOx
20 emission allowances, can significantly change the dispatch order for our units
21 during the ozone season. This is because the NOx penalty for the smaller coal units
22 is significantly greater than the penalty for the larger NOx controlled coal units or
23 the gas-fueled units. Typically, gas prices exceed coal prices by enough margin

1 that gas-fueled units always dispatch after coal. During the ozone season however,
2 depending on the relative price of gas, coal, and NOx emission allowances, a gas-
3 fueled unit, like the Richmond County Combined Cycle unit, may actually dispatch
4 ahead of some of the coal units. We experienced this situation in 2004 due to the
5 price gap between coal and gas narrowing as coal prices increased. Therefore,
6 there were times during the summer of 2004 that generation from our smaller coal
7 units would be shifted to either lower NOx emitting coal units such as Roxboro
8 Unit 4 and Mayo Unit 1 (which use more expensive coal) or to gas-fueled units
9 such as Richmond County CC. For the period of April 2004 through March 2005,
10 all of these factors combined to increase our total coal requirements by over
11 670,000 million tons, to increase our requirements for compliance coal by almost 1
12 million tons and to increase our requirements for natural gas by over 11 million
13 decatherms.

14 **Q. What changes do you see in the coal industry that will impact the Company's**
15 **cost of coal in 2005 and 2006?**

16 **A.** We anticipate no near term relief in coal prices. Consequently, as current below
17 market contracts expire and are replaced with new contracts, they will be at higher
18 prices. We have 25 current contracts expiring between April 2005 and December
19 2006 totaling 7.83 million tons over this period. Of the expiring contracts, 9 are
20 mid-term and/or long-term contracts totaling 5 million tons for the period April
21 2005-December 2006. As previously discussed, and illustrated in Coats Exhibit No.
22 4, coal prices escalated sharply throughout most of 2004. Even with these rising
23 prices, the Company recently negotiated a three-year deal for 1,000,000 annual tons

1 of non-compliance coal at an average price ranging from \$43.25-44.25/ton over the
2 contract term. These prices were more than \$13/ton below market at the time the
3 contract was negotiated. We are also in negotiations for another non-compliance
4 coal contract at below market prices. The Company expects, however, that market
5 prices will remain high in the near term. There is no indication that any of the
6 factors causing the higher prices described earlier in my testimony will ameliorate
7 significantly during the period that rates from this proceeding will be in effect.
8 Based on these factors, the Company's fuel costs are projected to be higher in the
9 July 2005 through June 2006 time period than experienced during the period of
10 April 2004 through March 2005. As shown on Coats Exhibit No. 3, we project
11 coal prices for July 2005 through June 2006 to average \$51.75/ton, exclusive of
12 transportation.

13 **Q. In PEC's 2004 fuel case, what did PEC forecast its transportation costs would**
14 **be for coal for the period April 2004-March 2005?**

15 A. As indicated on Coats Exhibit No. 3, our average transportation cost was forecast
16 to be \$14.40/ton the period.

17 **Q. What were the actual transportation costs for the same period?**

18 A. Our actual transportation cost was \$15.76/ton.

19 **Q. What are you projecting for coal transportation costs for the future period of**
20 **July 2005 through June 2006.**

21 A. For this period, we project average coal transportation costs of \$19.82/ton.

22 **Q. Why did transportation costs increase for these two periods?**

1 A. As I mentioned earlier, about 70% of our coal is burned at our Roxboro and Mayo
2 plants. These plants are served solely by the NS. When the existing transportation
3 contracts with NS were set to expire in March 2002, PEC worked diligently to
4 negotiate a new contract at reasonable rates. These negotiations were not
5 successful, and as a last ditch effort to establish rates that we felt were reasonable,
6 we filed a complaint in February 2002 against NS with the federal Surface
7 Transportation Board (STB). Following a lengthy STB hearing, the Board issued a
8 decision in December, 2003 which established rates of approximately \$15/ton.
9 These rates were less than the rates that NS had sought in the earlier negotiations
10 and represented what we felt were reasonable rates for the transportation of coal to
11 our Roxboro and Mayo plants. In March 2004, NS appealed the STB board ruling
12 and in October, 2004, the STB issued a new ruling which had the effect of voiding
13 its earlier ruling and established significantly higher rates for service to Roxboro
14 and Mayo. The effect of the new ruling was to allow rates of approximately \$17.50/
15 ton. The STB ruling also allowed a fuel surcharge to be added to these rates. The
16 surcharge is currently 10% or \$1.75/ton. Thus the effect of this ruling was to
17 increase our transportation costs for coal to the Roxboro and Mayo plants by
18 \$4.25/ton. The new rates went into effect in November 2004 and are projected to
19 be in effect through the period of time covered by rates from this proceeding.

20 **Q. Has PEC taken any actions to appeal the more recent STB ruling?**

21 A. Yes. We have filed an appeal with the Surface Transportation Board requesting
22 that the new rates be phased in rather than increased all at one time. In addition,
23 we have filed an appeal in federal court challenging the inclusion of data after the

1 original decision was rendered. At this time, we cannot predict the outcome of
2 either action.

3 **Q. Please describe your procurement practices for natural gas?**

4 A. We follow a process that is very similar to that discussed earlier for coal.
5 Production costing models are used to project future demands. Based on the
6 projections, solicitations are made, bids received, and contracts are established to
7 cover 85% of our projected needs for the coming year and 60% of our needs for the
8 succeeding year. Long term contracts are established and maintained for gas
9 transportation; however commodity baseload contracts are currently established on
10 terms up to two (2) years. Typically, commodity contracts are established on the
11 basis of recognized industry prices indices with appropriate adders. On a short
12 term basis (weekly and monthly), we also project our need for natural gas and will
13 make additional purchases on the spot market as needed.

14 **Q. In PEC's 2004 fuel case, what were your projected requirements for natural**
15 **gas and how did that projection compare with your actual experience?**

16 A. We projected a requirement of 7.1 million Dt for the period of April 2004 through
17 March 2005 at an average commodity cost of \$5.68/Dt and a delivered cost of
18 \$9.40/Dt. Our actual requirements during this period were for 18.2 million Dt at an
19 average commodity cost of \$6.70/Dt. Because the fixed transportation costs were
20 spread over a larger than projected volume of natural gas, the actual delivered cost
21 decreased to \$8.31/Dt. We project a need for 20.5 million decatherms for the period
22 of July 2004 through June 2005 at an average commodity cost of \$8.89/Dt and a
23 delivered cost of \$10.21/Dt.

1 **Q. Why did your actual gas demand and commodity costs increase over your**
2 **projection for the period of April 2004 through March 2005?**

3 A. The reasons for the increased demand in the test period are the same as was
4 previously discussed regarding coal. We experienced higher load and energy
5 demand, less production from our nuclear plants than we had forecast, and the
6 impacts of greater than expected gas generation due to their operation during the
7 June-September, 2004 ozone season. On the cost side, continued volatility in the
8 gas markets, less than expected storage inventories, and continued perception of
9 high gas usage for power generation through the summer of 2004, tended to keep
10 natural gas commodity prices higher during the summer and fall of 2004 than had
11 been forecast. These factors are expected to continue for the near future and are
12 reflected in even higher forecasts for the future period of July 2005 through June
13 2006. Coats Exhibit No. 6 illustrates the market volatility that has existed in recent
14 years in the natural gas market and our current forecast for the future.

15 **Q. Does that complete your testimony?**

16 A. Yes it does.

PROGRESS ENERGY CAROLINAS, INC.
ANALYSIS OF QUALITY OF FUEL AS RECEIVED

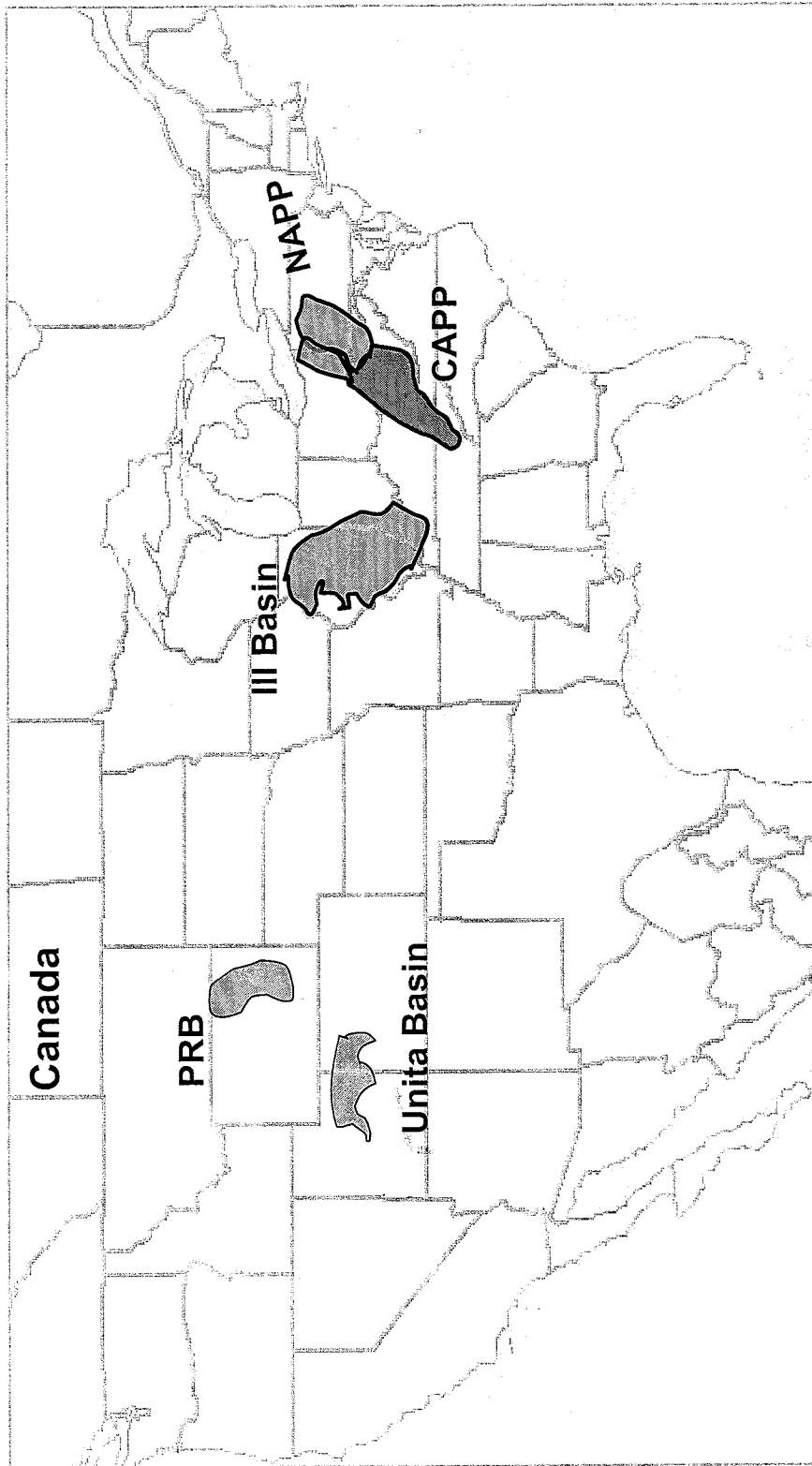
<u>Month</u> (a)	<u>Type</u> (b)	<u>Percent Moisture</u> (c)	<u>Percent Ash</u> (d)	<u>Percent Sulfur</u> (e)	<u>Btu/Pound</u> (f)
January 2004	Contract Coal	6.53	10.37	.84	12476
	Spot Coal	6.23	11.70	.94	12356
February 2004	Contract Coal	6.30	10.30	.81	12,492
	Spot Coal	6.43	11.32	.89	12,329
March 2004	Contract Coal	6.29	10.49	.79	12,443
	Spot Coal	6.45	11.02	.97	12,357
April 2004	Contract Coal	6.30	10.47	.80	12,490
	Spot Coal	6.66	12.04	.91	12,257
May 2004	Contract Coal	5.84	11.02	.84	12,446
	Spot Coal	6.08	12.10	.97	12,310
June 2004	Contract Coal	6.34	10.78	.82	12,433
	Spot Coal	6.52	11.71	.91	12,214
July 2004	Contract Coal	6.18	10.35	.85	12,460
	Spot Coal	6.76	11.46	.90	12,318
August 2004	Contract Coal	6.02	10.86	.82	12,443
	Spot Coal	7.94	9.81	.95	12,153
September 2004	Contract Coal	6.44	10.38	.88	12,448
	Spot Coal	7.26	10.88	.90	12,196
October 2004	Contract Coal	6.40	10.06	.83	12,447
	Spot Coal	6.38	11.67	.92	12,320
November 2004	Contract Coal	6.47	10.14	.86	12,508
	Spot Coal	7.14	10.94	.93	12,289
December 2004	Contract Coal	6.39	10.62	.91	12,421
	Spot Coal	7.37	11.18	.89	12,166

PROGRESS ENERGY CAROLINAS, INC.
ANALYSIS OF QUALITY OF FUEL AS RECEIVED

<u>Month</u> (a)	<u>Type</u> (b)	<u>Percent Moisture</u> (c)	<u>Percent Ash</u> (d)	<u>Percent Sulfur</u> (e)	<u>Btu/Pound</u> (f)
January 2005	Contract Coal	6.27	10.91	.87	12,419
	Spot Coal	6.64	10.68	.91	12,465
February 2005	Contract Coal	6.42	10.83	.88	12,457
	Spot Coal	6.07	10.23	.85	12,674
March 2005	Contract Coal	6.45	10.57	.87	12,455
	Spot Coal	6.61	9.88	.75	12,612

Supply Regions

Coats Exhibit No. 2
Docket No. 2005-1-E



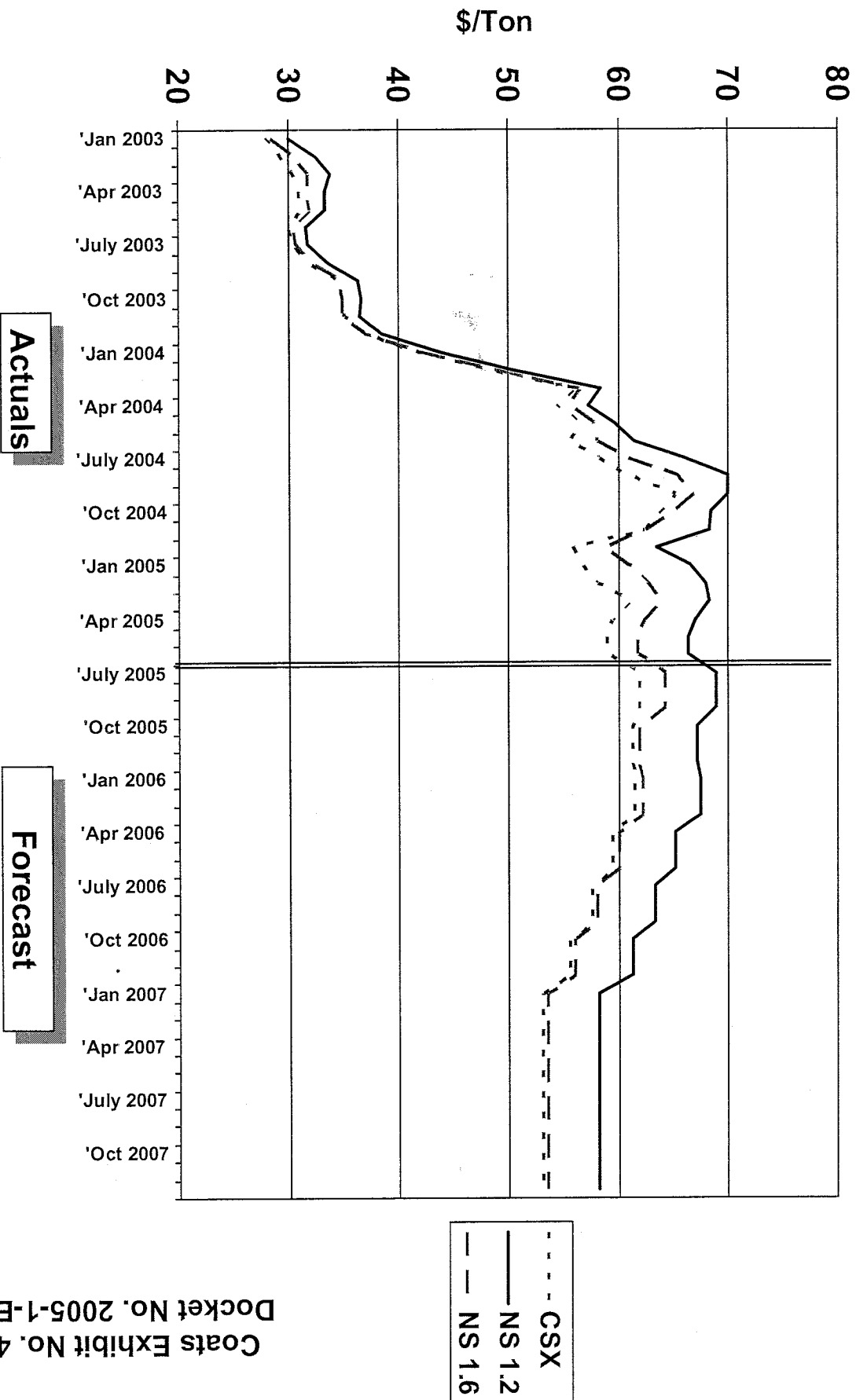
Planned vs Actual Coal Requirements
April 2004-March 2005

		Planned		
	Tons	Coal \$/ton	Trans \$/ton	Del'd \$/ton
Compliance Coal	2,642,439	\$32.44	\$14.57	\$47.00
Non-Compliance Coal	8,766,117	\$31.43	\$14.35	\$45.77
Total Coal	11,408,556	\$31.66	\$14.40	\$46.05
Actual				
Compliance Coal	3,625,816	41.32	16.99	58.32
Non-Compliance Coal	8,453,832	41.44	15.06	56.5
Total Coal	12,079,648	\$42.01	\$15.76	\$57.77
Changes	671,092	\$10.35	\$1.36	\$11.72

Projected Coal Requirements
July 2005-June 2006

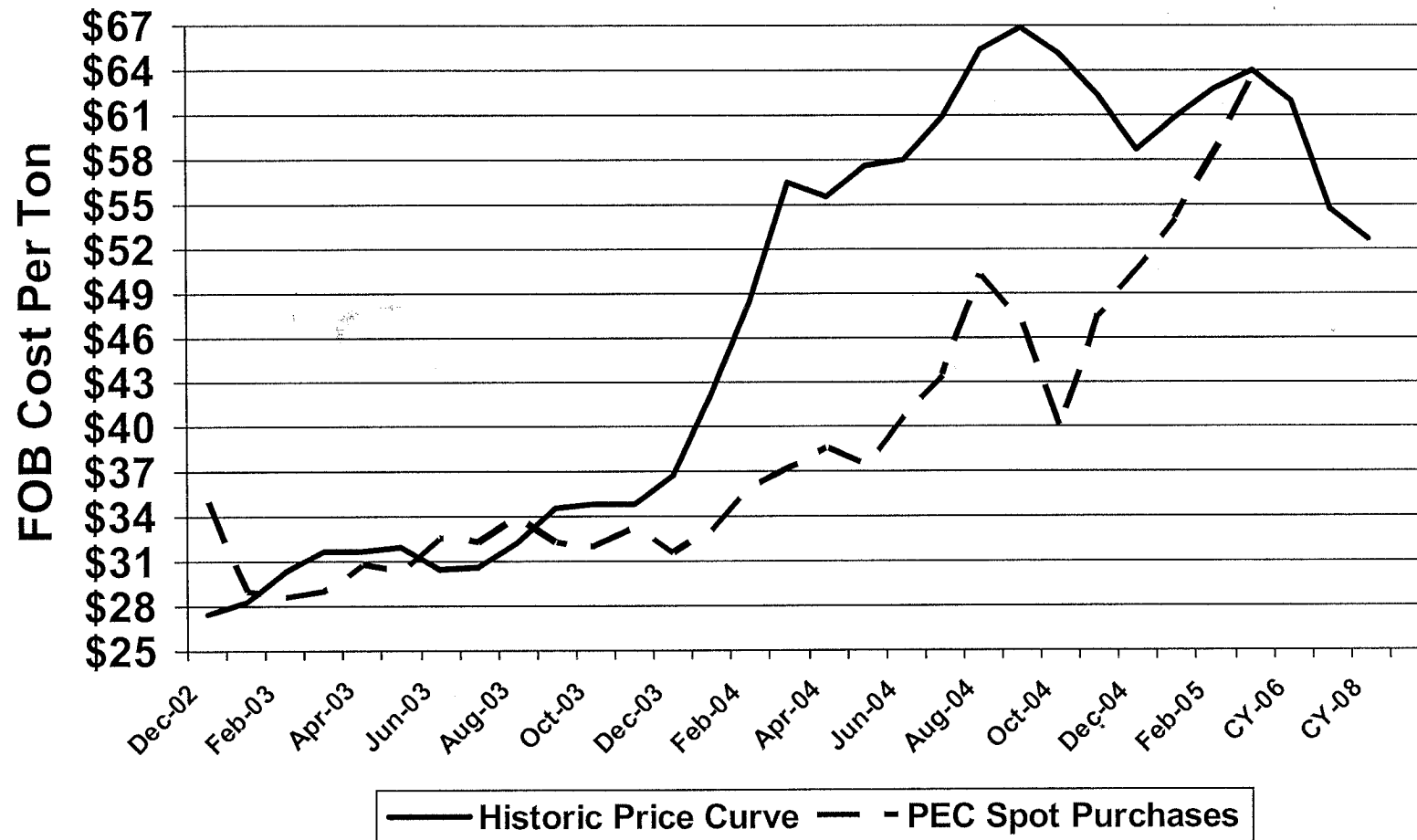
Compliance Coal	3,949,539	\$50.40	\$22.18	\$72.59
Non-Compliance Coal	9,167,294	\$52.33	\$18.80	\$71.13
Total Coal	13,116,833	\$51.75	\$19.82	\$71.57

CAPP Coal Prices



Spot Market

NS 12500 Btu, 1.6# Coal



UPICoal Historic Spot Prices
PEC-Coal Received Report

Coats Exhibit No. 5
Docket No. 2005-1-E

Gas Prices Trends

